BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2021-88-E

Dominion Energy South Carolina, Incorporated's 2021 Avoided Cost Proceeding Pursuant to S.C. Code Ann. Section 58-41-20(A)	))))))	**PARTIAL PROPOSED ORDER OF CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION**

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I. INTRODUCTION[1]

This matter comes before the Public Service Commission of South Carolina ("Commission") pursuant to the requirements of S.C. Code Ann. § 58-41-20 as contained in 2019 Act No. 62 ("Act No. 62"), which was enacted into law by the South Carolina General Assembly and became effective on May 16, 2019. Specifically, Act No. 62, also known as the Energy Freedom Act, directed the Commission to "open a docket for the purpose of establishing each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement this section." S.C. Code Ann. § 58-41-20(A).

In compliance with Act No. 62, on March 10, 2021, the Commission established the above-captioned docket for the purpose of establishing Dominion Energy South Carolina, Inc.'s ("DESC" or the "Company") standard offer, avoided cost methodologies, form contract power purchase agreements ("PPAs"), commitment to sell forms, and any other terms or conditions necessary to implement the requirements of S.C. Code Ann. § 58-41-20.

The Energy Freedom Act is a wide-ranging law passed by the South Carolina General Assembly in the wake of the V.C. Summer debacle, which left South Carolinian ratepayers paying some $9 billion dollars for two nuclear units that South Carolina Electric and Gas ("SCE&G," now DESC) and the South Carolina Public Service Authority ("Santee Cooper") partially constructed and then abandoned before commercial operation. A central feature of the Energy Freedom Act is Section 20, governing this Commission's proceedings under the Public Utilities Regulatory Policies Act ("PURPA") (codified at 16 U.S.C. §§796, 824a-3). Section 20 of the Energy Freedom

[1] Much of the language of this section of CCEBA's Proposed Order is taken from the Brief prepared and submitted by Pine Gate. CCEBA commends the brief to the Commission in its entirety.

Act specifically directs the Commission to consider measures to "promote the state's policy of encouraging renewable energy." S.C. Code Ann. § 58-41-20(F)(2).

With the passage of PURPA in 1978, Congress sought to encourage the development of alternative energy production facilities. In Section 210 of PURPA, Congress established a mandatory market mechanism whereby electric utilities are required to buy from qualifying small power production and cogeneration facilities ("Qualifying Facilities" or "QFs") at a price equal to that which the utility would otherwise pay to generate or purchase elsewhere. 16 U.S.C. § 824a-3(b). Congress instructed the Federal Energy Regulatory Commission ("FERC") to certify such facilities and establish rules to "encourage" small power production facilities and "require" them to "purchase energy from such facilities" using rates that must be "just and reasonable to the electric consumers of the electric utility and in the public interest" and which "shall not discriminate against [Qualifying Facilities]," with avoided energy rates not to cannot exceed "the incremental cost to the electric utility of alternative electric energy." Id.

A. The Energy Freedom Act and PURPA

As noted above, a central feature of the Energy Freedom Act is Section 20, which for the first time sets forth detailed provisions governing this Commission's implementation PURPA. While the Commission had been implementing PURPA for decades since that federal statute's enactment, the General Assembly saw fit to enact significant new statutory language governing avoided cost proceedings. Among other things, the law separates each investor-owned utility's PURPA proceedings from its annual fuel rider dockets – which had left the Commission and parties little time to investigate the utilities' avoided cost filings – and empowers the Commission to engage an independent third-party consultant to assist in resolving these important, but highly complex, proceedings.

Along with evident intent to require greater scrutiny of utility avoided cost filings, the General Assembly also made clear that it understood PURPA to be an important avenue for bringing renewable power into investor-owned monopoly service territories. Act 62's PURPA provisions require that the Commission treat qualifying facilities in a fair and non-discriminatory manner, consider prohibiting charges on QFs for utility integration costs, and review PURPA contract length to "promote the state's policy of encouraging renewable energy." S.C. Code Ann. § 58-41-20(F)(2).

The General Assembly's intent fits with the overall purpose of PURPA to "encourage" small power production facilities and "require" utilities to "purchase energy from such facilities" at rates that equal the utility's incremental energy costs, are "just and reasonable" to consumers and "in the public interest," and that "shall not discriminate against" Qualifying Facilities. 16 U.S.C. § 824a-3(b).

B. The Avoided Cost Provisions Applicable to this Proceeding

Section 20(A) of the Energy Freedom Act sets forth a number of factors that must be considered in any decisions regarding PURPA and QFs. Section 58-41-20(A) directs that the Commission open PURPA dockets for the various utilities and render decisions that are: "just and reasonable to ratepayers," "in the public interest," "consistent with PURPA and FERC's implementing regulations and orders," "non-discriminatory to small power producers (QFs)," and which must "strive to reduce the risk placed on the using and consuming public."

While some of these factors reference long-standing ratemaking principles ("just and reasonable"), others are newer concepts and require interpretation and reference to the Energy Freedom Act more broadly. As to the "public interest," for example, the General Assembly elsewhere in the Energy Freedom Act's PURPA provisions "expressly directed" the Commission in reviewing QF contract lengths to consider the "potential benefit" of longer terms to "promote the state's policy of encouraging renewable energy." 58-41-20(F)(2). Thus, the state's public policy, expressly set out in these provisions, is to encourage renewable energy, and that must be considered as part of the public interest.

Similarly, the requirement that decisions be "non-discriminatory" to QFs was a new concept. Section 58-41-20(B) requires that QFs be treated "on a fair and equal footing" with utility-owned resources. Thus, where a utility does not charge shareholders to pay for costs incurred integrating its own generation resources, such charges cannot be passed along to QFs. The General Assembly's heightened concern for such discrimination is underscored by Energy Freedom Act Section 20(E)(3)(B), which directs the Commission to consider whether to "prohibit" PPA terms "reducing the price paid" to QFs due to the utility's claimed costs of integrating intermittent QF power.

While Section 20(A) sets out various factors for the Commission to optimize, Section 20(B) establishes more specific requirements for the Commission in evaluating avoided cost rates, contract terms, and methodologies used to determine the VIC. At a minimum, Section 20(B) requires that in implementing the statute's PURPA provisions the Commission "shall treat small power producers on a fair and equal footing," and sets forth three subsections to achieve that result for (1) avoided cost rates, (2) agreement terms and conditions, and (3) methodologies for determining avoided and incurred costs.

First, as to "rates" for the purchase of "energy and capacity" Section 20(B)(1) requires that such rates "fully and accurately" reflect the utility's avoided costs. By explicitly requiring that such rates not just accurately reflect a utility's avoided costs, but also "fully" do so, this requirement fits with Section 20(B)'s overriding directive that small power producers be treated "on a fair and equal footing" with utility-owned resources. If is there is a band of uncertainty or dispute around a utility's calculated avoid costs, for example, that uncertainty must be resolved so as to ensure that any and all avoided costs are "fully" compensated to QFs.

Second, as to QF power purchase agreements, Section 20(B)(2) requires that terms and conditions be "commercially reasonable" and consistent with federal standards. Again, this fits with 58-41-20(B)'s controlling directive that small power producers be treated "on a fair and equal footing" with utility-owned resources. Commercially unreasonable terms would not treat QFs on fair and equal footing. And while DESC has argued that the Commission cannot apply a "commercially reasonable" standard, the statute could not be clearer in requiring that this very standard be applied in reviewing the terms and conditions of DESC's proposed PPAs and NOC forms.

Third, Section 20 (B)(3) addresses the broader issue of "methodology." Specifically, it requires that the utility's avoided cost "methodology fairly accounts" for costs "avoided" or "incurred" by the utility, "including, but not limited to energy, capacity, and ancillary services provided by or consumed by small power producers." S.C. Code § 58-41-20(B)3). Like subsections 1 and 2, subsection 3 is in service of Section 20(B)'s overarching requirement that small power producers be treated "on a fair and equal footing" with utility-owned resources, which it does by requiring that a methodology "fairly account[]" for costs avoided or incurred, including ancillary services.

Subsection 3 is the provision applicable to the Variable Integration Charge ("VIC"), which concerns DESC's claimed future costs of integrating intermittent solar resources. Because a VIC must "fairly" account for costs avoided and incurred and do so in a way that treats small power producers "on a fair and equal footing" with utility-owned resources, a charge that singles out QFs and treats them on unfair and unequal footing with utility's owned resources cannot be approved. This means that DESC, to have its VIC approved, must show that the costs for integrating its own resources (e.g., building turbines to provide back-up power for nuclear units, for example, or the costs of curtailing gas generation due to minimum nuclear unit operating levels) are charged to DESC shareholders rather than to ratepayers.

Section 20(E)(3)(B) of the Energy Freedom Act directs the Commission to consider whether PPAs should "prohibit" outright any terms "reducing the price paid" to QFs based on costs incurred by the utility "to respond to the intermittent nature" of QF production. S.C. Code 58-41-20(E)(3)(B). By directing the Commission to consider whether to prohibit such charges, the General Assembly clearly empowered the Commission to prohibit or reduce them in its review of utility proposals.

Finally, as relevant to the VIC, the statute requires that the utility must offer a "fixed price" contract. S.C. Code Ann. § Section 20(F)(2). The Parties to this proceeding have engaged in substantial discussions about whether a contract that includes a variable integration charge subject to modification based on future analysis and proceedings is or is not a "fixed price" contract under the statute.

II. NOTICE AND INTERVENTIONS

On April 30, 2021 the Commission Clerk's Office filed a Notice of Filing and Hearing and Prefile Testimony Deadlines, setting forth deadlines and advising all persons who wished to participate as a Party of Record of the manner and time in which to file appropriate proceedings. DESC filed Affidavits attesting to publication of the Notice on May 24, 2021.

Timely Petitions to Intervene were received from Johnson Development Associates, Inc. ("JDA"); the Carolinas Clean Energy Business Association ("CCEBA"); the South Carolina

Department of Consumer Affairs ("DCA"); the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy (collectively, "CCL/SACE"); Pine Gate Renewables, LLC ("Pine Gate"). DESC did not oppose the Petitions to Intervene and no other parties sought to intervene in this proceeding. The South Carolina Office of Regulatory Staff ("ORS") also is a party of record pursuant to S.C. Code Ann. § 58-4-10(B).

III. PREHEARING MATTERS

On April 22, 2021, DESC filed its Application to Approve and Establish the Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and All Other Appropriate Terms and Conditions ("Application"). On May 12, 2021, the DCA filed a Motion for Review of Application Sufficiency, arguing that the initial Application "other than requesting approval for the continuation of a previously approved DDR methodology … [did] not identify 'clearly and concisely' the 'specific relief sought' – in this case the standard offer, avoided cost methodologies, form contract PPAs, commitment to sell forms, and other appropriate terms and conditions." Instead, DCA stated, "[i]t merely iterates, without explanation that these items will be provided at a later date." (DCA Motion for Review of Application Sufficiency at 3.)

In its Application, DESC stated that it would provide the additional items for approval as part of its direct testimony. DCA argued that this tactic would cost the other parties two months of preparation time and leave them with "only two weeks to review DESC's actual relief sought" before the then-scheduled hearing date. (*Id.*) DCA's Motion was supported by Intervenors CCEBA and SCCL/SACE. DESC filed a letter in opposition to the Motion on May 24, 2021.

The Commission granted DCA's Motion via Directive Order 2021-384, finding that DESC's Application "does not confirm with Regulation 103-823, which requires it to provide sufficient information." The Commission ordered DESC to amend its Application and submit it as part of an amended Application by June 7, 2021.

DESC filed its Amended Application on June 7, 2021 ("Amended Application"). This Amended Application included nine attachments, including:

- Rate PR-Avoided Costs Methodology tariff—clean and redline copies are attached as Exhibit 1.
- Proposed avoided costs, attached as Exhibit 2.
- Rate PR-1-Small Power Production, Cogeneration tariff—clean and redline copies are attached as Exhibit 3.
- Rate PR-Standard Offer tariff—clean and redline copies are attached as Exhibit 4.
- Standard Offer contract—clean and redline copies are attached as Exhibit 5.
- Rate PR-Form PPA tariff—clean and redline copies are attached as Exhibit 6.
- Form PPA—clean and redline copies are attached as Exhibit 7.
- NOC Form—clean and redline copies are attached as Exhibit 8.
- Solar Site Variability Metric mitigation protocol, attached as Exhibit 9.

(Amended Application at 5.)

After DESC filed the Amended Application, the Clerk's Office issued a Revised Notice of Filing and Hearing and Prefile Testimony Deadlines on June 16, 2021. The Notice set the hearing to begin on August 18, 2021 with pre-filed testimony due from DESC on June 29, 2021, from other parties of record on July 13, 2021, and with rebuttal testimony due on July 27, 2021 from DESC and surrebuttal from other parties on August 10, 2021. DESC filed pre-filed direct testimony from its witnesses on June 29, 2021, including Direct Testimony and Exhibits of James W. Neely, Allen W. Rooks, John E. Folsom, Jr., Peter David, Daniel Kassis, and Eric H. Bell.

Thereafter, DESC filed a Second Amended Application on June 25, 2021, stating that "In the course of preparing its direct testimony for filing, the Company has updated certain information, including changes to the proposed tariffs." (Second Amended Application at 4.) Changes included in the Second Amended Application included a revised VIC calculation, revised language in the proposed contracts, and correction of scrivener's errors.

After exchanges of discovery and the filing of the Second Amended Application, CCEBA moved to extend time for discovery and various other deadlines. After resolving the disputed discovery issues, CCEBA filed a Consent Motion, joined by DESC, to extend certain deadlines. The Commission entered Directive Order 2021-504 on July 21, 2021, continuing the date for prefiling of intervenor testimony until July 27, 2021, with rebuttal due from DESC on August 10, 2021 and from Intervenors on August 16, 2021. The Commission denied CCEBA's Motion to continue the August 18, 2021 hearing date.

On July 27, 2021, SCCL/SACE filed testimony and exhibits from witness Kenneth Sercy. CCEBA filed testimony and exhibits from witnesses Edward Burgess and Steven J. Levitas. The Office of Regulatory Staff filed testimony and exhibits from Brian Horii and O'Neil O. Morgan. DESC filed rebuttal testimony from witnesses Rooks, Kassis, Bell, Neely, Folsom, and David as well as additional rebuttal witness Thomas E. Hanzlik, on August 10, 2021. Intervenors then filed surrebuttal testimony on August 16, 2021. CCEBA filed testimony from witnesses Burgess and Levitas. SCCL/SACE filed testimony from witness Sercy. ORS filed surrebuttal testimony of witness Horii.

The distanced hearing began on August 18, 2021 and continued until August 25, 2021. DESC and all Intervenors were represented by counsel throughout the proceeding.

In addition to the initial round of testimony, and pursuant to Act 62, the Commission engaged an independent third party expert to review the applications filed by DESC. An initial Request for Proposals ("RFP") for such services was issued on April 19, 2021 pursuant to the Commission Directive of March 31, 2021. Only one offer was received by the relevant deadline, and a Statement of No Award was accordingly filed on May 17, 2021. In Directive Order 2021-363, the Commission ordered a new RFP be issued. The new RFP was issued on May 24, 2021 requiring submissions by June 3, 2021.

On June 9, 2021, the Commission entered Directive Order 2021-413 requiring a third RFP be issued, and the Clerk issued that RFP on June 16, 2021, requiring any proposals to be submitted on or before June 20, 2021. On July 14, 2021, the Commission issued a Notice of Receipt of Proposals in Response to RFPs, detailing four proposals received in this docket. The entities submitting the proposals were publicly interviewed on July 21, 2021. The Commission chose the proposal presented by London Economics International, LLC ("LEI") and issued a scope of work in Directive Order 2021-520 on July 29, 2021. On September 17, 2021, LEI filed its Independent Report ("the LEI Report"), which it amended and corrected on September 22, 2021.

The Commission set a schedule for a second round of hearings, addressing certain issues arising from the earlier hearings, and allowing testimony from LEI and the parties in response to the LEI Report. On October 5, 2021 CCEBA filed supplemental surrebuttal testimony of witness Burgess. On October 8, 2021, DESC filed responsive testimony from witnesses Bell, David, Folsom, Kassis and Neely. Also on October 8, 2021, CCEBA filed Responsive testimony and exhibits of witness Burgess, and SCCCL/SACE filed responsive testimony of witness Sercy. The second distanced hearing took place from October 11 – 13, 2021.

IV. HEARING

As noted above, the Commission convened the initial distanced hearing to hear testimony, receive documentary evidence, and consider the merits of the case on August 18, 2021, continuing the hearing until August 25, 2021. At this first hearing, the Honorable Justin Williams, Chairman of the Commission, presided. DESC was represented by K. Chad Burgess, Esq.; Matthew W. Gissendanner, Esq., Mitchell Willoughby, Esq. and Tracey C. Green, Esq. JDA was represented by Courtney Walsh, Esq. and Weston Adams, III, Esq. Richard L. Whitt, Esq. jointly represented Pine Gate and CCEBA, and was joined by J. Blanding Holman, IV Esq. for Pine Gate and John D. Burns, Esq. for CCEBA. Kate Lee Mixson, Esq. and Emma C. Clancy, Esq. represented SCCCL / SACE. Roger P. Hall, Esq., Carri Grube Lybarker, and Connor J. Parker, Esq. appeared on behalf of the DCA. The ORS was represented by Alexander W. Knowles, Esq. In this Order, DESC, JDA, CCEBA, SCCCL/SACE, Pine Gate, DCA and ORS are collectively referred to as the "Parties" or sometimes individually as a "Party."

During the first hearing, DESC presented testimony from witnesses Neely, Rooks, Folsom, David, Kassis, and Bell. CCEBA presented responsive direct testimony from witnesses Levitas and Burgess. SCCCL/SACE presented responsive direct testimony and exhibits from witness Sercy. The ORS presented testimony from witnesses Horii and Morgan. JDA presented no witnesses during the hearing.

DESC also presented rebuttal testimony from witnesses Rooks, Kassis, Bell, Neely, Folsom, and David as well as additional rebuttal witness Hanzlik. These witnesses presented their direct and rebuttal testimony during the same session, and were cross-examined upon both by counsel for other Parties and questioned by the Commission. Likewise, witnesses Levitas, Burgess, Horii, and Sercy presented their surrebuttal testimony at the same time as their direct testimony, and were cross-examined on both by counsel to the Parties and questioned by the Commission.

The Commission began the second phase of hearings on October 11, 2021, lasting until October 13, 2021. The Honorable Florence P. Belser, Vice Chair of the Commission, presided. During that hearing, DESC witness David was briefly cross-examined, and CCEBA presented supplemental surrebuttal testimony by witness Burgess. Witness Burgess was cross examined by DESC's counsel and questioned by the Commission. LEI then presented its report through the testimony of A.J. Goulding. CCEBA witness Burgess testified in response. SCCCL/SACE presented responsive testimony from witness Sercy, and DESC presented responsive testimony from witnesses Folsom and David. The Parties made closing arguments on October 13, 2021, and the hearing was adjourned.

V. FINDINGS OF FACT[2]

Based on the testimony and exhibits received into evidence at the hearings and the entire record of these proceedings, the Commission hereby makes the following findings of fact:

A. Variable Integration Charge

1. The Commission finds that the determination by ORS, LEI, and CCEBA that DESC has not justified its incremental operating reserve requirement (which is the theoretical basis for the VIC) is supported by the evidence in the record. Additionally, DESC's system operations manager, Witness Hanzlik, had not reviewed the Guidehouse VIC Study in preparation for his testimony, and the Company's other witnesses indicated the Guidehouse recommendations for operating reserves were still being taken under

[2] As to the issues related to Avoided Cost Rates and Methodologies, CCEBA refers the Commission to the proposed Partial Order submitted on those issues by SCCCL/SACE. CCEBA adopts the proposed Findings of Fact and Conclusions of Law put forward in that proposed Partial Order.

consideration and are not currently the basis for integrating solar onto the DESC system.

2. The Commission finds that neither ORS nor LEI provided any independent quantitative analyses or alternative VIC studies to support their recommendation of a fixed VIC equal to DESC's original proposal of $1.80/MWh for Tranche 1.
3. The Commission finds that there are numerous methodological flaws with DESC's VIC study, all of which caused DESC's proposed VIC to be higher than the correct value. These methodological flaws include but are not limited to: a) inadequate application of hourly weighting based on modeled solar output, b) inaccurate model representation of the Fairfield Pumped Storage Facility's capabilities, c) incorrect allocation of integration costs to Tranche 1 facilities, and d) a recommended increase in the level of operating reserves that is unsupported by historical data, current operating practices (i.e., 40% of forecasted solar), or a transparent model forecast.
4. The Commission finds that hourly weighting should have been used to more accurately assess the actual operating reserves needed in any given hour to accommodate unexpected drops from solar on the DESC system, rather than using a single reserve requirement for every hour of each month. The failure to use hourly weighting improperly inflates integration costs because that maximum reserve value is in turn used to set the operating reserve required for every solar production hour during a given month, regardless of time of day or weather conditions. The Commission finds that the correct application of hourly weighting to DESC's VIC Study, as presented in Mr. Burgess' testimony, would result in a VIC of $0.73/MWh for Tranche 1 (absent any other changes).

5. The Commission finds that the Fairfield Pumped Storage Hydro facility was not modeled by Guidehouse in a manner that reflects the real-world operation and capabilities of that facility, which led to inflated cost calculations for the VIC. A correct model representation of Fairfield should reduce the VIC relative to DESC's original proposal.
6. The Commission finds that the Guidehouse study did not properly account for the impacts of its baseline solar assumptions and their impact on integration costs calculated for Tranche 1 solar. There was no system-operations basis to delineate solar into tranches simply based on whether a facility's PPA does or does not contain a VIC clause.
7. The Commission finds that Guidehouse's use of a VBA-based proprietary model resulted in a lack of transparency as to how geographic diversity was integrated into the model, which may have led to inflated cost calculations for the VIC.
8. DESC erred in using a 4-hour forecast rather than a more accurate 1-hour forecast when calculating its solar forecast error assumptions. The Commission finds that forecast error is a key metric in Guidehouse's calculation a solar integration charge and that use of a 1-hour forecast would have reduced forecast error by 40% to 50%. A 1-hour forecast is consistent with best practices for system operators.
9. DESC's actual operating reserves have tended to be significantly higher than the Company's minimum operating reserve requirement, and DESC has not quantified any actual integration costs incurred as it has integrated approximately 863 MW of solar onto its system over the past several years. The Commission finds that the Company's historical operating reserves are relevant to the VIC and should be accounted for when

calculating any cost for additional operating reserves necessary to accommodate solar on DESC's system.

10. The Commission finds that CCEBA Witness Burgess did conduct a detailed quantitative analysis of DESC's VIC study in developing his recommended alternative integration charge. This analysis relied upon the same scenarios, inputs, and model results as those used in DESC's VIC study, except for limited and targeted post-modeling corrections, for example to apply hourly weighting consistent with the original Guidehouse approach.
11. The Commission finds several of Mr. Burgess's post-modeling corrections to be reasonable including a) use of hourly weighting, which reduces the Tranche 1 VIC to \$0.73/MWh, and b) transparent cost allocation which further reduces the Tranche 1 VIC to \$0.47/MWh.
12. The Commission finds that PPAs with a fixed VIC should be made available to small power producers.
13. The Commission finds that the LEI Report did not properly consider the analysis of Witness Burgess with regard to its recommendations on a fixed VIC, and that the evidence in the record does not support adoption of a \$1.80/MWh VIC, especially in light of Act 62's requirements to treat QFs in a non-discriminatory manner, its explicit policy stated in the Act's PURPA provisions of encouraging renewable energy, the de minimus risk to customers of setting the VIC at a lower level.
14. The Commission finds that an independent integration study conducted consistent with Order No. 2020-244 and the recommendations of ORS and LEI to be justified.

15. The Commission finds that the statutory bar for transparency of utility filings in avoided cost cases to be higher than simple compliance with the rules of discovery, and therefore future utility filings must ensure that underlying assumptions, data, and results can be independently reviewed by the parties and the Commission, as required by statute. DESC did not meet that standard in this proceeding.
16. The Commission finds that a fixed VIC of $0.73/MWh is supported by the evidence in this proceeding and the corrective calculations provided in the testimony of CCEBA Witness Burgess.

B. Mitigation Protocol

17. The Commission finds that the proposed VIC mitigation protocol is based on a flawed framework and contains unduly burdensome and discriminatory features.

C. Contractual Issues

18. The Commission adopts in part and rejects in part DESC's proposed changes to the Notice of Commitment Form as set forth in the Company's Second Amended Application, as further amended by testimony. The proposed form is commercially reasonable except as to the following:
    a. The Commission finds that DESC's proposed changes to the Site Control provisions of paragraphs 4(iii) and 4(iv) are unnecessary to the creation of a Legally Enforceable Obligation under PURPA and are therefore not commercially reasonable.

b. The Commission finds that the Parties have agreed upon commercially reasonable language for Paragraph 8(ii) of the Proposed NOC Form related to termination as submitted in Revised Exhibit JEF-1.

19. The Commission adopts in part and rejects in part DESC's proposed changes to the Form PPA and Standard Offer as submitted in the Company's Second Amended Application, as further amended by testimony. These proposed forms are commercially reasonable except as to the following:

a. The Commission finds that DESC has failed to relate its proposed increases in minimum insurance coverage to any particular risk or condition of operation at a QF Facility, whether subject to the Form PPA or the Standard Offer. The Commission further finds that compliance with parental corporate practice is not sufficient to impose additional burdens on QF developers. Those proposed increases are therefore not commercially reasonable. It is, however, reasonable to require automobile liability insurance coverage in the amount of $1,000,000.

b. The Commission finds that DESC has failed to relate the proposed changes in revised paragraph 8 of the Surety Bond form (Exhibit F to the Form PPA and the Standard Offer) to any particular risk or condition of operation at a QF Facility. The Commission further finds that compliance with parental corporate practice is not sufficient to impose additional burdens on QF developers. The changes included in Revised Paragraph 8 of the Surety Bond form are therefore not commercially reasonable.

c. The Commission finds that DESC has not justified the inclusion of ancillary services as energy products provided by QFs to DESC free of charge.

VI. REVIEW OF THE EVIDENCE AND EVIDENTIARY CONCLUSIONS

A. Summary of DESC's VIC

Witness Peter David, Associate Director with Guidehouse, sponsored a study titled "Variable Integration Cost" on behalf of DESC. (H.E. 3.) The study purported to identify any increase in system operating costs that result from maintaining a minimum operating reserve requirement sufficient to account for solar forecast error associated with various levels of solar penetration on the DESC system. (Tr. Vol. 3 p. 54, line 24 – p. 55, line 21.) The VIC study concluded that:

1. As solar penetration increases on the DESC system, the levelized cost of maintaining additional operating reserves will increase due to less efficient system operations. (Tr. Vol. 3 p. 57, lines 6 – 9.)
2. No integration costs should be attributed to the first 340 MW of solar integrated onto DESC's system. This 340MW of baseline solar was identified by virtue of the projects not having a PPA clause that would allow imposition of a VIC.
3. Integration costs of $1.80/MWh should be attributed to 633 MW of solar in Tranche 1, which is in addition to 340 MW of baseline solar. Tranche 1 was identified as having a variable integration charge clause in their PPAs. (Tr. Vol. 3 p. 67, line 22 – p.57, line 5.)
4. Integration costs of $3.43/MWh are attributable to the next 100 MW of solar beyond the baseline and Tranche 1 solar, making up Tranche 2. (Tr. Vol. 3 p. 57, lines 10 – 13.)
5. Integration costs of $4.64/MWh are attributable to an additional 300 MW of solar beyond Tranche 2, making up Tranche 3. (Tr. Vol. 3 p. 57, lines 13 – 16.)

B. Forecast Error

EVIDENCE AND CONCLUSIONS SUPPORT FINDING OF FACT NO. 3 and 8

Summary of Evidence

Guidehouse conducted a solar uncertainty analysis to determine the forecast error from solar on an hourly basis and the amount of operating reserves necessary to reliably operate the DESC system while accommodating unanticipated drops in solar production. (David Direct at p. 9, lines 1 – 5.) In its analysis of potential forecast error, Guidehouse used an NREL solar dataset that includes historical 5-minute generation data from locations corresponding to solar facilities on the DESC system and contrasted the NREL production estimates of those facility locations against the NREL 4-hour ahead forecast for those same locations. (*Id*. at lines 6 – 18.) Witness David noted that ideally a 1-hour ahead forecast would have been used but that data was not available. (*Id*. at lines 9 – 21.) At the hearing, Mr. David confirmed that a 1-hour forecast would be more accurate and would lead to a reduced potential for solar forecast error. (Tr. Vol. 3 p.72, lines 22 – 24.) ORS Witness Hori cited an independent study showing that solar forecast errors could be reduced by about 50% if 1-hour ahead schedules are used. (Horii Direct at p. 9, lines 6 – 9.) And in his surrebuttal testimony, Witness Horii refuted claims by DESC Witnesses Bell and Hanzlik that a more accurate 1-hour forecast would not reduce the VIC based on the actual methodology used by Guidehouse to calculate the VIC. (Horii Rebuttal at p. 2, lines 4 – 13.)

CCEBA Witness Burgess testified that a 1-hour forecast is superior to a 4-hour forecast because it more accurately predicts the meteorological conditions that dictate solar output, resulting in a lower probability for significant error. (Burgess Direct at p. 25, line 2 – p. 26, line 2.) Witness Burgess further testified that because DESC establishes its operating reserves based on an hourly forecast, a 40% reduction in forecast error should be accounted for and applied to the

Guidehouse VIC calculations. (*Id*. at p. 29, line 24 – p. 30, line2.) Witness David confirmed that a 40% reduction of forecast error could be expected with the use of 1-hour instead of 4-hour forecast data. (Tr. Vol. 3 p, 74, lines 4 – 12.)

Witness Hanzlik testified that he had not actually reviewed the Guidehouse VIC study and was not familiar with the methodology used by Guidehouse to calculate the VIC. (Tr. Vol. 1 p. 212, line 25 and p. 213, line 1; Tr. Vol. 2 p. 34, lines 9 – 11.) Witness Hanzlik further testified that, in its real-world operations, DESC uses an internal forecast that is "fairly accurate" as to the peak output of solar in any particular hour. (Tr. Vol. 1 p. 221, lines 3 – 5.) Additionally, Witness Hanzlik acknowledged that the graphs presented as part of his testimony from the stand did not include the DESC forecast for hourly solar production. (Tr. Vol. 2 p. 33, lines 1 – 7; Tr. Vol. 2 p. 33, lines 24 – 25 and p. 34, line 1.)

Commission Conclusions

Because forecast error is a key variable in the Guidehouse VIC study, the Commission finds that it is appropriate to use the more accurate forecast methods employed in DESC's actual operations, which include the use of a 1-hour solar forecast that is "fairly accurate," as testified to by Witness Hanzlik. Witness David described the use of a 1-hour forecast to be "ideal."

Witness Hanzlik acknowledged that charts showing drops in solar production, which were presented as part of his testimony from the stand, failed to include DESC's *forecast* of solar production. Since the Guidehouse VIC study is predicated on *unexpected* (i.e., unforecasted) drops in solar production, Mr. Hanzlik's charts are not indicative of the magnitude of forecast error because they do not differentiate between expected and unexpected drops in solar.

Witnesses Horii and Burgess identified studies finding that forecast error can be reduced by 40% to 50% by using 1-hour forecast data rather than a 4-hour forecast, and Witness Burgess recommends that a 40% reduction in forecast error be applied to Guidehouse's VIC calculations to fit with the actual use of 1-hour forecast data. We agree.

C. DESC's Historical Operating Reserves

EVIDENCE AND CONCLUSIONS SUPPORT FINDING OF FACT NO. 3 and 9

Summary of Evidence

The Guidehouse VIC study is based on what Guidehouse believes DESC's operating reserve requirement should be, not what it presently is or has been in the past. (David Rebuttal at p. 13, lines 1 – 3.) Witness Bell testified that actual operating data does not provide a basis for calculating the VIC. (Bell Rebuttal at p. 7, lines 19 – 20.) Nonetheless, Witness Hanzlik testified DESC's actual operating practice is to hold operating reserves equal to 40% of forecasted solar production to account for both expected and unexpected drops in solar production. (Tr. Vol. 1 p. 208, line 25; *Id*. at p. 209, lines 1 – 6; *Id*. at p.209, lines 22 – 25 and p. 210, lines 1 – 2.) Mr. Hanzlik also stated that there are times when that 40% operating reserve requirement is too low, but he did not differentiate unexpected drops from expected drops in solar production, while the Guidehouse VIC calculations, which Mr. Hanzlik had not reviewed, are predicated on unexpected drops in solar production. (Tr. Vol. 1 p. 218, lines 3 – 23.) Witness David testified that DESC has not had an event in the last two years where the amount of operating reserves held by DESC was insufficient to cover unforecasted solar drops. (David Rebuttal at p.5, lines 14 – 15.)

Witness Burgess testified, and DESC Witness Bell concurred, that DESC has historically carried operating reserves that far exceed DESC's 250 MW baseline reserve requirement, which was also used as a baseline in the Guidehouse study. (Burgess Surrebuttal at p. 22, line 18 – p. 23, line 3.) Additionally, Mr. Burgess used information provided by DESC to establish that the Company's typical operating reserves far exceed what Guidehouse claims is necessary to integrate solar Tranches 1, 2, and 3. (Burgess Direct at p. 14, lines 19 – 21.) During cross examination, Mr. Burgess corrected Witness Hanzlik's misconceptions about the use of average monthly operating reserves also being representative of the underlying minute-to-minute data provided by DESC to intervenors. (Tr. Vol. 5 p. 24, lines 16 – 25 and p. 25, lines 1 – 16.) When examining the underlying data, the historical operating reserves have actually been higher than what the Guidehouse study claims is needed to integrate solar Tranches 1, 2, and 3. (*Id*. p. 73, lines 2 – 5.) Specifically, in response to Mr. Hanzlik's chart showing a 251 MW solar drop related to Tropical Storm Fred on August 17, 2021, Mr. Burgess showed that in the 2020 to 2021 timeframe, there were zero instances where DESC's actual operating reserves were less than 251 MW. Even if DESC had doubled the level of required reserves to 502 MW while solar was producing during the 2020 to 2021 timeframe, only 0.4% of solar production hours coincided with historical operating reserves that were below that level, further illustrating the excessive reserve recommendations of the Guidehouse study that would apply to 100% of solar production hours. (Id. p. 23, lines 1 – 21.)

In Order No. 2020-244, this Commission required that a true-up for the interim VIC be based on the "actual integration cost" indicated by an integration study, and Mr. Burgess noted in his testimony that the Guidehouse VIC study does not attempt to quantify any actual integration costs incurred in DESC's historical operations. (Burgess Direct at p. 8, lines 6 – 11.) Witness Bell testified that "accurately identifying the VIC in historical data is not practical." (Bell Rebuttal at p. 5, lines 4 – 5.)

Commission Conclusions

The Commission determines that the true-up for the interim VIC set in 2019 should be based on actual historical integration costs as required in Order No. 2020-244. Based on the evidence in the record, Guidehouse did not rely on DESC's actual historical operations when calculating a VIC for Tranche 1.

The Commission also finds that, based on actual operational data, DESC's historical operating reserves, even prior to adding solar to its system, have been significantly higher than its minimum operating reserve requirement. This fact should be properly accounted for when calculating any incremental operating reserve requirement, as well as any VIC costs associated therewith.

D. Incremental Operating Reserves

EVIDENCE AND CONCLUSIONS SUPPORT FINDING OF FACT NO. 1 and 3

Summary of Evidence

The calculation of incremental operating reserves was developed by Guidehouse predicated on its solar uncertainty analysis, which projected the magnitude of potential solar drops due to forecast error. (David Direct at p. 9, lines 1 – 5.) Guidehouse's model used Monte Carlo draws to estimate incremental operating reserve requirements to avoid NERC violations on a 15-minute interval. (*Id*. at p. 10, lines 11 – 19.)

The calculated costs to maintain incremental, or additional, operating reserves is the main driver of VIC costs. (David Direct at p. 13, lines 1 – 13.)

DESC Witness Bell testified that the Company is still evaluating the results of the Guidehouse study to determine the necessary level of additional reserves that might be needed. (Bell Rebuttal at p. 3, lines 18 – 19.) Mr. David also testified that he understood DESC to be taking the Guidehouse VIC study "under advisement." (David Rebuttal at p. 7, lines 11 – 12.) As noted previously, Witness Hanzlik testified that he had not actually reviewed the Guidehouse VIC study and was not familiar with the methodology used by Guidehouse to calculate the VIC. (Tr. Vol. 1 p. 212, line 25 and p. 213, line 1; Tr. Vol. 2 p. 34, lines 9 – 11.)

Witness Horii concluded that Guidehouse "has not justified their forecast of incremental operating reserves needed to accommodate solar forecast uncertainty." (Horii Direct at p. 8, lines 15 – 17.) The Commission's expert, LEI, did not conduct a full independent analysis of the Guidehouse Study due to resource constraints and its view that the VIC was not squarely within its purview to independently analyze. (Burgess Responsive Testimony at p. 2, lines 1 -16.) LEI agreed, however, with Mr. Horii's assessment that the incremental reserves used in the VIC study had not been fully justified. (Tr. Vol. 7 at p. 67, line 25 – p. 68, line 6.)

Witness Burgess was the only witness to analyze the Guidehouse methodology in detail, and he concluded that the corrected workbook provided by Witness David does not support the incremental operating reserves recommended in the VIC study. Rather, the dataset identified in Mr. David's corrected testimony showed that the Guidehouse study modeled monthly incremental operating reserves that are 70% to 150% higher than needed to address the most extreme single hour – or the hour with the highest solar production – in the model's 10-year forecast. (Burgess Supplemental at p. 7, lines 20 – 22; p. 8, lines 1 – 20; and p. 9, lines 1 – 2.) Mr. Burgess also conducted an analysis of Mr. David's corrected dataset reference by applying DESC's existing operating practice of maintaining reserves to meet a 40% unanticipated drop in solar production. When this real-world practice is applied to the Guidehouse workbook, all reserve shortfalls for Tranche 1 are eliminated and all but < 0.01% of shortfall hours are eliminated for Tranche 2. These results were confirmed by DESC in discovery responses to CCEBA. (*Id*. at p. 7, lines 3 – 19.) Mr. Burgess also testified that no party to this proceeding had actually seen the underlying methodology used by Guidehouse to determine the appropriate level of incremental operating reserves. (Id. at p. 8, lines 11 – 12.)

Commission Conclusions

The Commission agrees with Witnesses Horii and Burgess that DESC has not justified its forecast of incremental operating reserves needed to accommodate solar forecast uncertainty. Because the calculation of incremental operating reserves relies on Guidehouse's flawed solar forecast error analysis, which used a 4-hour solar forecast rather than the 1-hour solar forecast actually used by the Company, the incremental reserve needs identified in the Guidehouse study substantially overstate the incremental operating reserves required to reliably integrate solar onto DESC's system, and likewise overstates the cost of those incremental operating reserves. As calculated by Witness Burgess, DESC's current practice of maintaining 40% operating reserves would accommodate all reserve shortfall hours for Trance 1 and 99.99% of reserve shortfall hours for Tranche 2.

Furthermore, DESC's system operator, Witness Hanzlik, had not reviewed the Guidehouse study or its methodology and could not testify to the veracity of Guidehouse's specific analysis and conclusions. Finally, witnesses for DESC and Guidehouse noted that the results of the Guidehouse study were still being evaluated by the Company and would be taken under advisement. This lack of commitment from DESC to actually implement the Guidehouse recommendations, which is not consistent with DESC's actual operating practice integrating over 800MW of solar, also makes adoption of the study recommendations by this Commission untenable.

E. Hourly Weighting

EVIDENCE AND CONCLUSIONS SUPPORT FINDING OF FACT NO. 3 and 4

Summary of Evidence

DESC's existing operating practice for solar integration consists of carrying operating reserves in the amount of 40% of the hourly solar forecast or 40% of actual solar generation. (Burgess Direct at p. 19, lines 20 – 22; Tr. Vol. 1 p. 211, lines 8 – 10.) That is, the Company uses hourly forecasts and adjusts the levels of reserves according to the magnitude of predicted solar production, so that smaller levels of reserves are needed in predictably lower production hours (dawn, dusk, forecasted cloud cover).

Contrary to the Company's current practice, the Guidehouse VIC study calculated the cost of carrying additional operating reserves adequate to account for a system wide unforecasted 60% drop in solar production over a single hour. (David Rebuttal at p. 17, lines 15 – 19.)

The Guidehouse VIC study relied on the modeling tool PROMOD, which does not allow operating reserve levels to change day-to-day or hour-to-hour. Rather, the model requires incremental operating reserves, and the costs of carrying those reserves, to be calculated for each month of the year based on the single highest hour of solar production during that given month. (David Direct at p. 25, lines 1 – 2.) For example, for *every* single solar production hour in April, PROMOD includes the cost of carrying operating reserves sufficient to address the maximum drop experienced in *any* hour of April. As Witness David stated, this means that even at 7 a.m., PROMOD would require that 557 MW of operating reserves be carried and would calculate the costs of incremental reserves attributed to that hour of solar production. (Tr. Vol. 3 p. 85, lines 11 – 21.)

To account for this limitation within PROMOD, Witness David testified that he originally applied hourly weighting to prorate integration costs by hourly solar generation – but then abandoned this approach. (David Rebuttal at p. 18, lines 4 – 9.) Instead of hourly weighting, Guidehouse used binary weighting whereby the incremental costs of additional operating reserves were applied to all daylight hours, but not to nighttime hours. (Tr. Vol. 3 p. 81, line 23; p. 82, lines 1 – 5.) As noted, this change applies a fixed monthly incremental operating reserve based on the highest expected solar production hour in a given month to predictably low solar production hours, such as morning, evening and on predictably cloudy days. (Burgess Supplemental at p. 1, lines 18 – 23.) Mr. David attributed his abandonment of hourly weighting and his preference for binary weighting to the operating constraints of DESC's thermal units, which includes start costs and minimum up and down times. (David Rebuttal at p. 18, lines 5 – 12.) Witness Horii clarified that DESC's perspective on this issue is incomplete because different generating sources have different timescales over which they can respond. The fact that some baseload units must be dispatched the day prior does not mean that other resources can't be dispatch within the day, hour, or on an even shorter time span. (Horii Rebuttal at p. 2, lines 18 – 23; p. 3, lines 1 – 6.) Witness Horii also testified that questions exist about the modeling results because PROMOD is just not the best tool to do the VIC analysis. (Tr. Vol. 6 p. 42, lines 13 – 16.)

Mr. Burgess testified that the magnitude of solar variability is undisputedly smaller during forecastable low solar production hours (dawn, dusk, predicted cloudy days), which is why hourly weighting is essential to accurately capture the costs of accommodating solar variability on DESC's system. (*Id.*) Without hourly weighting, the costs underlying the VIC assume that DESC has to maintain the same level of operating reserves during all solar operating hours in each month. (*Id.*) During cross examination, Mr. Burgess also corrected the erroneous assertion by DESC

Witness Hanzlik that Mr. Burgess's analysis relied on averaging DESC's monthly historical operating reserves, which it did not, and pointed out that it is the Guidehouse analysis that uses a monthly flat number for the operating reserve input. (Tr. Vol. 5 p. 61, lines, 13 – 25.) This results in the model assuming that in a month like January, Guidehouse's model requires DESC to carry a constant 244 MW level of incremental reserves during all daylight hours, including midday hours and evening hours, even though those hours will have predictably different levels of solar generation and a lower magnitude of forecast error in the evening. (Burgess Rebuttal at p. 1, lines 18 – 23; and p. 2, lines 1 – 5.)

Commission Conclusions

The Commission agrees with Witness Burgess that Guidehouse's abandonment of hourly weighting to compensate for the limitations of PROMOD resulted in an overstatement of the costs of actual incremental operating reserves that would be required by DESC to reliably operate its system. It is not reasonable, nor is it supported by the evidence in this record, that DESC would need to carry the same operating reserves to accommodate solar on a predictably cloudy day, or during dawn and dusk hours, as it would in the middle of a sunny day with intermittent cloud cover.

The Commission also recognizes that the failure to use hourly weighting further compounds the decision by Guidehouse to calculate solar forecast error using a 4-hour rather than a 1-hour solar forecast. The cascading impact of the exaggerated forecast error calculation led to inflated incremental operating reserve assumptions that were then applied as a flat monthly operating reserve requirement to every solar production hour of the month without regard for time of day or weather conditions.

F. Fairfield Pumped Hydro Facility

EVIDENCE AND CONCLUSIONS SUPPORT FINDING OF FACT NO. 3 and 5

Summary of Evidence

The Guidehouse study is described by Witness David as allowing the Fairfield Pumped Storage facility to provide operating reserves when called on and to generate energy to reduce load on DESC's system. (David Direct at p. 25, lines 13 – 15.) On rebuttal, Mr. David states that Fairfield was modeled with no variable costs, no start costs, minimum up and down times of 1 hour, and a minimum generation level of 0.1% of its maximum capabilities. (David Rebuttal at p. 16, lines 1 – 4.) Guidehouse also acknowledged that Fairfield could switch modes to provide operating reserves when offline or pumping in less than 15 minutes. (David Rebuttal at p. 14, 20 – 22.) DESC confirmed in discovery that Fairfield can be ramped up in approximately 3 minutes. (Burgess Supplemental at p. 6, lines 6 – 7.)

However, the Guidehouse report did not recognize Fairfield as a quick-start resource. (Exhibit No._(PBD-2) at p. 15, Table 5.) Mr. David confirmed from the stand that Fairfield was not modeled as a quick start resource because Guidehouse had not conducted the modeling exercise necessary to determine Fairfield's availability related to factors such as reservoir levels. (Tr. Vol. 3 p. 99, lines 1 – 10.) Witness Hanzlik, DESC's system operator, testified that he did not know how the Guidehouse study modeled Fairfield. (Tr. Vol. 1 p. 238, lines 18 – 21.)

Witness Burgess cited discovery provided by the company confirming that the 576 MW Fairfield Pumped Hydro Storage facility was excluded by Guidehouse from providing any operating reserves unless the facility was already pumping or generating, which is inconsistent with the facility's quick-start abilities and how DESC actually operates Fairfield in the real world. (Burgess Rebuttal at p. 6, lines 1 – 8.) Furthermore, DESC confirmed that Fairfield was not allowed to provide any operating reserves in its modeling results during the hours where there would be a potential for a reserve shortfall due to solar intermittency. Mr. Burgess testified that if Fairfield had been made available by the model, it would have been able to eliminate all of the hours with a reserve shortfall for Tranche 1 at no cost, and possibly all of the hours with a reserve shortfall for Tranche 2 as well, although the discovery responses did not contain the relevant information for confirming that conclusion with regard to Tranche 2. (Id. at lines 8 – 15.)

Finally, Mr. Burgess testified that DESC provided no historical data or evidence to suggest that low reservoir capacity would be a limiting factor during the reserve shortfall hours that were modeled, and in fact, past experience demonstrates that the Fairfield reservoir is at least partially filled over 95% of all hours during a year. (Burgess Supplemental at p. 9, lines 8 – 13.)

Commission Conclusions

The Commission finds that DESC has not justified the modeling constraints placed on the Fairfield Pumped Hydro Storage facility, and that but for those limitations, Fairfield would likely be available to meet at no cost a significant portion of the operating reserves the Company requires for integrating solar on its system. The Guidehouse VIC study did not model Fairfield in a way that reflects how the Company actually operates that facility in the real world, which results in an artificially higher cost for solar integration than would actually be expected in practice.

G. Geographic Diversity

EVIDENCE AND CONCLUSIONS SUPPORT FINDING OF FACT NO. 7

Summary of Evidence

Because solar facilities are not all located at a single location on the DESC system, and since weather can vary significantly between locations, incorporating the geographic diversity of solar facilities into the Guidehouse VIC study is an important consideration so as not to overstate the total amount of solar forecast uncertainty that DESC must accommodate. (David Direct at p. 20, lines 13 – 21; and p. 21, lines 1 – 5.) Failing to account for geographic diversity would lead to higher operating reserves, and in turn, higher estimated solar integration costs. (*Id*. at p. lines 9 – 14.) Witness David testified that geographic diversity is accounted for within the model through the use of NREL solar forecast and production data from a wide array of sites across the DESC footprint, which was then fed into a VBA-based model to conduct Monte Carlo draws comparing actual solar generation to the scheduled data. (David Rebuttal at p. 11, line 21; and p. 12, lines 1 – 12.)

Witness Burgess testified that Guidehouse did not demonstrate how the data used from multiple sites was actually aggregated and evaluated, and that the algorithm showing how this aggregation was done was never made available by DESC. (Burgess Surrebuttal at p. 10, lines 15 – 23; and p. 11, lines 1 – 2.) Mr. Burgess also discovered an incorrect formula error in the workbook provided by DESC as an "illustrative example" of how solar sites were aggregated within the Guidehouse study, which suggests a similar error could have been made in the actual study. (*Id*. at p. 11, lines 2 – 5.) The failure of DESC to provide the proprietary VBA-based model to other parties in this proceeding resulted in a "black box" that obfuscated the underlying methodology used by Guidehouse to account for geographic diversity in its study. (Id. at p. 11, lines 22 – 23; p. 12, line 1; and p. 12, lines 8 – 10.)

Finally, Mr. Burgess testified that discovery responses provided by DESC reveal the assumption that drops in solar production will occur simultaneously at all solar facilities, rather than some of them, indicating that the study does not properly account for geographic diversity. (Burgess Supplemental at p. 5, lines 13 – 21.) Mr. David defended this discrepancy by stating that the Guidehouse study does not make any claims as to which specific solar facilities may experience unexpected drops at any given time, but rather it relies on an extensive analysis to determine a total drop in aggregate facility production of 60% is possible. (David Rebuttal at p. 17, lines 15 – 19.)

Commission Conclusions

The Commission finds that due to a lack of transparency related to Guidehouse's decision to use a VAR-based proprietary model, it is not possible to determine whether the effects of geographic diversity were properly integrated into the Guidehouse VIC study. The Commission is also concerned by the illustrative examples provided by DESC in discovery, which fail to reflect any geographic diversity within those illustrative examples, but instead show simultaneous drops in solar production across the DESC system.

H. Cost Allocation Between Solar Tranches

EVIDENCE AND CONCLUSIONS SUPPORT FINDING OF FACT NO. 3 and 6

Summary of Evidence

The Guidehouse study purports to calculate a separate integration charge for three different tranches of solar, taking into account the baseline amount of solar on DESC's system that is not subject to an integration charge (Exhibit No._(PDB-2) at p. 6).

Table 1. Solar Capacity by Tranche

	Baseline	***Tranche 1***	***Tranche 2***	***Tranche 3***
Incremental	340 MW	633 MW	100 MW	300 MW
Total	340 MW	973 MW	1073 MW	1373 MW

Based on Guidehouse's recommendation for DESC's incremental operating reserve requirement, Guidehouse used PROMOD to model the cost of adding those incremental operating reserves to the DESC system for each tranche of solar and then compared that to a base case without the incremental operating reserves in order to calculate an integration charge for each tranche of solar. (*Id*. at p. 7.) Witness David testified that Guidehouse did no analysis on the proper level of operating reserves for the 340 MW of baseline solar. (David Rebuttal at p. 21, lines 17 – 20.)

Witness Burgess testified that because Guidehouse modeled Tranche 1 as 973 MW of total solar on the DESC system, rather than just the 633 MW of solar that is actually contained in Tranche 1, there are integration costs attributable to the 340 MW of baseline solar that are improperly being assigned exclusively to Tranche 1. (Burgess Direct at p. 22, line 24 – p. 23, line 9.) To correct for this error, Mr. Burgess adjusted the appropriate formula in the relevant Guidehouse workbook so as to allocate the integration costs identified in the model to all solar production MWhs from both the baseline and Tranche 1, instead of just the solar production MWhs from Tranche 1. (*Id*. at p. 29, lines 1 – 12.) This correction ensures that the principle of cost causation is upheld and that integration costs calculated in the Guidehouse model are fairly allocated to Tranche 1. (*Id*. at p. 23, lines 7 – 9.)

On rebuttal, Mr. David testified that no costs should be allocated to the baseline solar because all of the incremental increases in minimum operating reserve requirements were calculated for Tranche 1 and therefore the increase in costs are attributable specifically to Tranche 1. (David Rebuttal at p. 22, lines 1 – 4.) Mr. Burgess disagreed with Mr. David's reasoning in that it suggested the 340 MW of baseline solar facilities have zero effect on total operating reserve needs for Tranche 1. (Burgess Rebuttal at p. 17, lines 20 – 21.) Mr. Burgess further testified that it is reasonable to expect that if the 340 MW of baseline solar were removed from the modeling, then fewer incremental operating reserves would be required to support the 633 MW of Tranche 1. (*Id*. at line 21; and p. 18, lines 1 – 5.) Finally, Mr. David acknowledged during the hearing that the reason for delineating the baseline solar from the Tranche 1 solar was simply because the baseline solar had no VIC clause in the PPAs and the Tranche 1 solar PPAs did include a VIC clause. (Tr. Vol. 3 p. 69, lines 16 – 25; and p. 70, lines 1 – 2.)

<u>Commission Conclusions</u>

The Commission determines that DESC failed to fully account for the modeling and cost implications of Guidehouse's baseline solar assumptions and their impact on integration costs calculated for Tranche 1 solar. Mr. David testified that Guidehouse did no analysis with regard to the proper level of operating reserves needed to accommodate the baseline solar on DESC's system. Mr. David also testified that the reason the 340 MW of baseline solar was delineated from Tranche 1 solar was simply an artifact of contracting language that either did or did not include a VIC clause. The Commission finds the allocation adjustment proposed by Mr. Burgess will ensure Tranche 1 solar facilities are not unfairly burdened by costs that are attributable to the baseline solar facilities that do not have a VIC clause in their PPAs.

I. Statutory Requirement to Establish a Fixed VIC

EVIDENCE AND CONCLUSIONS SUPPORT FINDING OF FACT NO. 12

Summary of Evidence

Witness Burgess testified that a fixed integration charge should be adopted in this proceeding and that continued uncertainty around a future VIC "true up" presents commercially unreasonable uncertainty for current and future QFs and an unnecessary burden for QFs seeking project finance. (Burgess Direct at p. 27, lines 23 – 29.) Witness Levitas testified that the current interim VIC has created considerable uncertainty for QFs with regard to PPA execution, incurring of development expenses, securing of project finances, and the sale of projects in operation or development. (Levitas Direct at p. 18, lines 12 – 19.) Mr. Levitas recommended that a fixed VIC should be adopted by the Commission and remain in effect for the life of the PPA. (Id. at lines 20 – 23; and p. 19, lines 1 – 8.) Witness Kassis disputed the commercial difficulties that have resulted from the interim VIC and testified that there are 17 PPAs with DESC that contain a VIC clause that executed prior to any VIC being set by this Commission. (Kassis Rebuttal at p. 14, lines 3 – 28; and p. 15, lines 1 – 2.) Mr. Levitas testified that he is unaware of any PPAs that have been executed since DESC proposed its very high VIC in Docket No. 2019-184-E and the interim VIC was adopted in that proceeding. Mr. Kassis confirmed from the stand that DESC has not executed any PPAs in the last two years that had an interim VIC, but he disputed that the interim VIC was responsible for this lack of PPA execution. (Tr. Vol. 1 p. 46, lines 22 – 25; and p. 47, line 1 – 15.)

Witness Levitas also testified that an indeterminate VIC is inconsistent with the requirements of Act 62, specifically Section 58-41-20(F), which requires "fixed price power purchase agreements" be made available to small power producers. (Levitas Rebuttal at p. 14, lines 8 – 16.)

The LEI Report stated that the biggest impact of an interim VIC is on those considering developing a project in South Carolina. (LEI Report at p. 55.)

Commission Conclusions

The Commission finds that a variable integration charge has inhibited QF development in DESC territory and that S.C. Code Section 58-41-20(F) requires that a PPA with a fixed integration charge be available to small power producers. Allowing the VIC charged under a PPA to be adjusted over time based on the results of additional study and analysis is not consistent with this requirement. Moreover, QF sellers should not be burdened with financial uncertainty due to DESC's failure to meet its burden of proof regarding a defensible and accurate accounting of its variable integration costs.

J. The LEI Report

EVIDENCE AND CONCLUSIONS SUPPORT FINDING OF FACT NO. 1, 2, and 13

Summary of Evidence

The LEI Report contains a high-level overview of the proposed VIC and the mitigation protocol and makes recommendations for how the Commission should consider deciding these issues. (LEI Report at Section 5.) LEI concluded that the extent of contrary evidence introduced regarding the VIC analysis supports the need for a truly independent study consistent with S.C. Code Section 58-37-60 to be conducted as soon as practical through a collaborative process where the inputs, assumptions, and methodological approach can be the subject of stakeholder consultation and feedback. (*Id*. at p. 54.) LEI recommended that the best approach is to maintain the current interim VIC at $0.96/MWh to trued up or down based on the results of the comprehensive independent study. (*Id*. at p. 56.) LEI also recommended that if the Commission sets a fixed VIC in this proceeding that it be set at $1.80 for Tranche 1 and any other contracted solar resources over the next two years. (*Id*.)

LEI based its $1.80/MWh recommendation on the fact that the Tranche 1 VIC was calculated based on the amount of solar already on DESC's system, its consistency with the Duke's integration charge established in 2019, and the range of integration charges in the Southeast. (*Id*.) LEI also confirmed that Mr. Horii's recommendation for a fixed VIC of $1.80/MWh was made from the stand during Commissioner questions and was not based on any quantitative analysis performed by Mr. Horii and presented in written testimony. (Tr. Vol. 7 p. 65, line 16 – p. 66, line 2.) LEI confirmed that because Mr. Horii made this recommendation from the stand during commissioner questions, no other party had an opportunity to cross examine Mr. Horii on this recommendation that was not included in his pre-filed written testimony. (*Id*. at p. 66, lines 3 – 7.)

Witness David disagreed with LEI that the Guidehouse Study was not truly an independent study. (David Responsive Testimony at p. 2, line 10 through p. 4, line 11.) Mr. David recommends that if a fixed VIC of $1.80/MWh is adopted for Tranche 1, then an interim VIC of $1.80/MWh to be trued up in the future would be a reasonable outcome for Tranche 2.

Witness Burgess testified that LEI did not conduct and thorough evaluation of the VIC, but instead produced a report that primarily consisted of contrasting statements from DESC's and CCEBA's witnesses. (Burgess Responsive Testimony at p. 1, lines 9 – 12.) In a response to CCEBA interrogatories, LEI defended its review level with regard to the VIC by citing its interpretation of Act 62 and indicating that the VIC was outside its scope of review. (*Id*. at p. 2, lines 1 – 16.) LEI confirmed that its review of the materials provided by DESC was sufficient to conclude that an independent study was necessary, and that neither LEI nor ORS Witness Horii had reviewed in detail the analysis conducted by Witness Burgess. (Tr. Vol. 7 p. 63, line 20 – p.

64, line 1; and p. 66, lines 8 - 16.) LEI also determined that DESC had not fully justified their conclusions regarding its forecast of incremental operating reserves. (*Id*. at p. 67, line 25 – p. 68, line 6.)

With regard to LEI's reliance on similar integration charges in the Southeast, Witness Burgess testified that the only two examples provided in the LEI Report were TVA, which is a self-regulated utility with no commission oversight, and Duke Energy, whose integration charge was the product of a settlement agreement. (Burgess Responsive Testimony at p. 3, lines 14 – 17.) The Duke Energy settlement agreement on the integration charge explicitly stated that it "will not constitute a precedent or evidence of acceptable practice in future proceedings." (Id. at p. 3, line 19 – p. 4, line 2.) At the hearing, LEI confirmed that it was not aware of any solar integration charge that had been adopted in Florida, the Number 3 ranked state for installed solar, or Georgia, the Number 4 raked state for installed solar. (Tr. Vol. 7 p. 80, 7 – 24.) Mr. Burgess further testified that there is no easy way to generalize what the integration costs would be from one utility system to the next and rough analogies are not a substitute for system specific analyses. (Burgess Responsive Testimony at p. 4, lines 3 – 9.)

Finally, Witness Burgess agreed with LEI's conclusion that the VIC is a small percentage of annual fuel costs. (Id. at p. 5, line 20 – p. 6, line 19.) Mr. Burgess calculated the de minimis impact on retail customers between a charge of $0.73/MWh and $1.80/MWh for Tranche 1 to be $0.00006/kWh, or about $0.06 on a typical residential customer's monthly bill. (*Id.*) Mr. Burgess agreed with LEI that the biggest impact that results from an unfixed VIC will be on those considering developing solar projects in South Carolina, and Mr. Burgess also testified that setting an artificially inflated VIC would likewise stymie market development for QF projects in DESC territory and contravene the state's policy of encouraging renewable energy. (Id. at p. 7, lines 1 – 7.)

Commission Conclusions

The Commission concurs with the LEI recommendation to conduct an independent integration study as outlined in the LEI Report. We also agree with the determination by LEI that DESC has not fully justified its incremental reserve forecast, and we therefore cannot support the LEI recommendation to set the VIC at $1.80/MWh. Furthermore, we find that it is not appropriate to base the VIC on integration charges developed for other utilities like TVA or Duke Energy, especially in the context of Duke, given the settlement agreement that resulted in Duke's integration charge. Given that LEI was not aware of any solar integration charges for other leading solar states in the Southeast, like Florida and Georgia, we find no compelling analogy for setting DESC's integration charge based on the information in evidence for peer utilities.

As acknowledged by LEI, Witness Burgess was the only intervening party in this proceeding to conduct a quantitative analysis of DESC's VIC proposal and provide alternative calculations for consideration by this Commission. We also recognize that neither ORS nor LEI conducted a detailed analysis of the work performed by Witness Burgess.

Finally, adopting the VIC as proposed by DESC is not supported by the evidence on the record, especially in light of the de minimis cost risk to customers and the disproportionate impact an artificially high integration charge could have for solar development in the state.

K. Independent Integration Study

EVIDENCE AND CONCLUSIONS SUPPORT FINDING OF FACT NO. 14

<u>Summary of Evidence</u>

Witness Horii testified that DESC's proposed VIC should not be adopted at this time because the Guidehouse VIC study has not its forecast of incremental operating reserves needed to accommodate solar forecast uncertainty. (Horii Direct at p. 8 line 1 and lines 15 – 17.) Mr. Horii recommended that the VIC remain at $0.96/MWh and remain subject to a future true up as contemplated in Order No. 2020-244. Witness Kassis testified that DESC is willing to accept Witness Horii's proposal to retain an interim VIC of $0.96/MWh subject to a future true up. (Kassis Rebuttal at p. 7, lines 1 – 4.) LEI concurred with Mr. Horii's recommendation and believes it to be the best approach. (LEI Report at p. 56).

As described above, Witnesses Burgess and Levitas testified that a VIC should be fixed as part of this proceeding due to negative impact of variable charges on QF development.

<u>Commission Conclusions</u>

The Commission finds that it must adopt a fixed VIC option for small power producers in this proceeding. This will satisfy the requirements of Act 62 until the requirements of Order No. 2020-244 and the recommendations of Witness Horii and LEI have been completed.

L. Transparency of DESC's Filing

EVIDENCE AND CONCLUSIONS SUPPORT FINDING OF FACT NO. 15

<u>Summary of Evidence</u>

Witness Burgess testified that none of the actual analysis supporting the need for incremental reserves was provided in DESC's initial application, amended application, or in direct testimony. (Burgess Supplemental at p. 11, lines 6 – 12.) A key component of DESC's analysis that was provided through discovery, the significance of which was downplayed in rebuttal testimony, was only accurately identified through a last-minute correction on the witness stand. (*Id*.) Mr. Burgess described the DESC's VIC analysis as a black box approach that did not reveal crucial algorithms used by the Company to calculate the operating reserve requirements that were central to its modeling. (Tr. Vol. 5 p. 11, lines 15 – 25; and p. 12, lines 1 – 5.)

Witness Horii testified that the Company provided information in its filings and data responses that were reasonably transparent. (Horii Direct at p. 4, 16 – 22.) Mr. Horii also testified that in the 2019 avoided cost proceedings he was able to make adjustments to amount of operating reserves proposed in that docket, but that there was not sufficient information provided in the current proceeding to make any kind of similar adjustment. (Tr. Vol. 6 p. 39, lines 7 – 13.)

LEI found that although DESC was highly responsive to interrogatories, there is room for improvement as it pertains to providing more detail in the Company's application so as to reduce stakeholder cost and the Company's burden of responding to interrogatories.

Witness Kassis testified that DESC had been transparent and met or exceeded the standard of transparency in Act 62, which requires avoided cost filings to be "reasonably transparent so that underlying assumptions, data, and results can be independently reviewed and verified by the parties and the commission." (Kassis Responsive Testimony at p. 2, lines 4 – 11.)

Commission Conclusions

The Commission finds that the standard for transparency was not met by DESC in this proceeding. Act 62 does not merely require that DESC comply with the rules on discovery, but that a utility's filings be reasonably transparent so that underlying assumptions, data, and results can be independently reviewed and by the parties and the commission. DESC has clearly not met this standard in the current proceeding. Given the time constraints and resource limitations that are inherent in complex proceedings such as avoided cost, in the future, utilities are required to include in their avoided cost application information adequate to ensure the underlying assumptions, data, and results are available to the parties and the Commission, as required by statute.

M. Alternative VIC Calculations

EVIDENCE AND CONCLUSIONS SUPPORT FINDING OF FACT NO. 10, 11, and 16

Summary of Evidence

Witness Burgess included the following VIC calculations in Table 2 below for Commissions consideration. The calculations are based on corrections to the flaws identified in the Guidehouse VIC study and are supported by the evidence cited thus far in this order and described in detail in Mr. Burgess's testimony. (Burgess Direct at p. 27, Section 8; and Burgess Supplemental at p. 11, line 13 – p. 12, line 10.)

Table 2.

	Tranche 1 VIC	**PPAs Executed Prior to an Independent Integration Study**
Recommendation based on DESC's historical operating reserves	$0/MWh	$0/MWh

Recommendation to properly allocate costs to baseline solar, apply hourly weighting, and include a 40% reduction in forecast error	$0.28/MWh	$0.71/MWh
Recommendation to properly allocate costs to baseline solar and application of hourly weighting to Tranche 1	$0.47/MWh	$0.73/MWh
Recommendation to apply hourly weighting to Tranche 1 and PPAs executed prior to an independent integration study	$0.73/MWh	$0.73/MWh

<u>Commission Conclusions</u>

The Commission finds that Mr. Burgess's alternative calculations provide credible alternatives based on corrective measures to the Guidehouse VIC Study that would not unfairly discriminate against QF developers. Based on these recommendations, the Commission hereby adopts a fixed VIC of $0.47/MWh for Tranche 1 and $0.73/MWh for any PPA executed prior to a future updated integration charge adopted by this Commission pursuant to the completion of an independent integration study.

N. VIC Mitigation Protocol

EVIDENCE AND CONCLUSIONS SUPPORT FINDING OF FACT NO. 17

Summary of Evidence

DESC filed a VIC mitigation protocol in its amended avoided cost application that describes a process for a QF to avoid paying some or all integration charges in each month, but it did not file direct testimony justifying the mitigation protocol. (Burgess Direct at p. 31, lines 14 – 17.) The mitigation protocol is based on a "solar site variability metric" ("SSVM") that calculates solar production variability on a 5-minute interval relative to the 5-minute interval one hour prior. For a maximum SSVM of 25% during a month, no integration charge is applied. For an SSVM between 25% and 45%, the facility pays half of the monthly integration charge, and for an SSVM above 45%, the full integration charge is paid. (*Id*. at p. 31, line 18 – p. 32, line 2.)

Witness Burgess identified four major flaws with the mitigation protocol. First, the SSVM should compare actual output to forecasted output, since the VIC is based on unexpected drops in solar resulting from forecast error. (Id. at p. 32, lines 8 – 19.) Second, the SSVM should capture hours with the greatest potential for a MW drop and not the greatest percentage drop, since MW drops correlate to larger operating reserve requirements, which is what the VIC is based on. This would also avoid unfairly penalizing solar for percentage changes during low production hours like morning and evening. (*Id*. at p. 32, lines 19 – 28.) Third, using an average SSVM instead of a maximum SSVM would more accurately capture the performance of a facility over the course of each month. (*Id*. at p. 33, lines 1 – 6.) Fourth, the SSVM should not necessarily be determined by a single facility if the portfolio of solar on DESC's system is compensating for a drop in one location as a consequence of overproduction at another location. (*Id*. at p. 33, lines 7 – 11.)

Because the proposed mitigation protocol does not allow for meaningful or realistic mitigation from solar facilities and is ultimately based on a relatively flawed framework, Mr. Burgess recommends that the Dominion Energy North Carolina mitigation protocol, which addresses most of the concerns outlined above, be adopted with a few additional modifications. (Id. at p. 33, line 12 – p. 34, line 27) The hourly variance should only summed for hours with underproduction and not overproduction; it should be allowable for solar developers to update their solar forecast on a more frequent basis; and QF owners should be able to aggregate multiple sites when performing the mitigation calculation. (Id. at p. 34, lines 1 – 14.)

The LEI Report recommended adopting DESC's concessions to Mr. Burgess's testimony, which included calculating solar QF production variability relative to forecast rather than actual, as well as allowing solar owners to aggregate production data across QF facilities that they own, but LEI did not recommend adoption of the Dominion Energy NC mitigation protocol. (LEI Report at p. 58.) With regard to the additional recommendations made in Mr. Burgess's testimony, LEI agreed that existing meters should be used for the SSVM to the extent practicable, but otherwise it is reasonable for the QF facility to purchase a separate meter. (*Id.*) LEI recommends that DESC proposal to require SSVM delivery within two days of months end as reasonable, rather than the 5 days recommended by Mr. Burgess. (*Id.*) Finally, LEI agreed with Mr. Burgess that DESC's proposed two-strike disqualification was unnecessary, could potentially harm customers, and should be rejected. (*Id.*)

The LEI Report did not discuss the Dominion Energy North Carolina mitigation protocol.

<u>Commission Conclusions</u>

The Commission finds that the mitigation protocol currently used by Dominion Energy North Carolina, with the modifications proposed by Witness Burgess, represents a fairer and nondiscriminatory option for QFs to mitigate solar integration charges. We agree that rather than modify the relatively flawed framework proposed by DESC in South Carolina, the utility and solar developers will be better served by applying a mitigation protocol that is already used by the Company and is supported by solar parties to this proceeding. The Commission also finds it necessary to adopt the recommendations from LEI to eliminate DESC's proposed two-strike rule, as it is unfair to QFs and potentially harmful to customers.

O. CONTRACT AND FORM ISSUES

DESC's currently-valid NOC Form, Form PPA and Standard Offer were approved by this Commission in Docket No. 2019-184-E. The Company seeks to change those documents, and filed proposed revised forms along with its First Amended Application.

DESC Witness Folsom introduced the NOC Form, Form PPA, and Standard Offer proposed by DESC. (Folsom Direct at 4, lines 2-8 (Hrg. Ex. 4).) Folsom is a Senior Market Originator for DESC. (*Id.* at p. 1, line 4.) He has worked for DESC or its predecessors since 1989 and has extensive experience in negotiating power supply agreements and Power Purchase Agreements ("PPAs") on behalf of DESC. (*Id.* at p. 2, line 2 – p, 3, line 1.) He has previously testified before this Commission on similar issues. (*Id.* at p. 3, lines 6-7.)

CCEBA and Pine Gate presented responsive testimony from Steven Levitas. Levitas is the Senior Vice President for Regulatory and Government Affair at Pine Gate. (Levitas Direct at p. 2, lines 5-6.) He has extensive experience in the representation of solar energy interests as a private attorney, government official, and corporate officer, including with the negotiation of model PPAs with Duke Energy as well as negotiated PPAs and contract documents on behalf of solar QFs with multiple utilities. (*Id.* at p. 2, line 9 – p. 4, line 23.) He has testified before this Commission and the Commissions of several other states. (*Id.* at p. 5, line 12 – p. 6, line 2.)

LEI also reviewed the proposed changes to the contractual forms and the testimony of the Parties regarding those changes. LEI made certain recommendations in its report and witness Goulding's testimony.

1. Changes to Notice of Commitment Form

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 18

Summary of Evidence

Witness Folsom first discussed the proposed changes to DESC's Notice of Commitment To Sell Form ("NOC Form"), which was attached as Exhibit 8 to DESC's Amended Application. He described the NOC Form as "a creature of Act 62" which requires that a QF "shall have the right to sell the output of its facility to the electrical utility at the avoided cost rates and pursuant to the power purchase agreement then in effect by delivering an executed [NOC Form]." (Folsom Direct at p. 7, lines 4-7.) He testified that the NOC Form allows a QF to "lock-in" avoided cost rates in exchange for its "substantial commitment" to sell the electrical output of its facility to the utility. (*Id.* at p. 7, lines 8-15.) Folsom then explained that the NOC Form operates to establish the Legally Enforceable Obligation ("LEO") under PURPA, a non-contractual but binding statement of intent to sell power generated by a QF.

Witness Levitas agreed that the NOC Form provided a basis for establishment of a PURPA LEO. He noted that FERC defined an LEO "by the QF's *commitment*, and not the utility's actions" to prevent utilities from frustrating the purpose of PURPA through delay and inaction. (Levitas Direct at p. 14, line 23 – p. 15, line 2.) He stated in his testimony that both PURPA and Act 62 "require this Commission to approve contract and NOC terms and conditions that strike a reasonable balance between the legitimate business interests of the QF and those of the utility in light of generally prevailing practice in the industry." (*Id*. at p. 7, lines 8-10.) Levitas testified that this standard of "commercial reasonableness" should be applied, and that "Contract terms that make it extremely difficult or impossible to finance QF development do not strike that balance and are discriminatory towards DFs." (*Id.* at p. 7, lines 10-12.)

Folsom stated that "[t]he NOC Form touches upon issues such as site control, delivery periods, and delivery deadlines as these provisions evidence substantial commitment and are important to ensure that the project is commercially viable and the developer has made a financial commitment to such project." (*Id.* at p. 9, lines 2-7.) He first addressed the concepts included in the currently-approved NOC Form, and then testified to the changes proposed by DESC. Folsom referenced the changes in Exhibit JEF-1 to his testimony (Hrg Ex. 4), which included a redlined copy of the NOC Form showing changes between the proposed version and the currently-valid NOC Form.

a. Changes to Accommodate Storage

The first substantive change to the NOC Form adds Section 3(ii) to add a category of "Facility Description" for Storage facilities, and sets forth questions related to the type and size of any storage devices included in a facility. Folsom testified that these changes assure that the type of storage facility is consistent with PURPA, and therefore "provide flexibility for developers to utilize storage in a variety of ways within this PURPA framework" and provide DESC with "sufficient information to provide rates that accurately reflect the avoided costs on the DESC system for such QF." (Folsom Direct at 13;1-15.) CCEBA and other Parties did not challenge the storage language included in the proposed NOC Form.

b. Site Control

The second substantive change to the NOC Form discussed by Folsom relates to proof of Site Control, which Folsom testified was a "fundamental element of substantial commitment." (*Id.*

at p. 14, line 7.) DESC proposed to "modify the NOC Form to require a certification that the QF has at least taken meaningful steps to obtain control of the project site and submitted all applications and filing fees necessary to operate and maintain the project." (*Id.* at p. 14, line 17 – p.15, line 1.) The two primary changes include the addition of a new section 4(iii), which would require the Seller (QF) to certify that it "has either commenced construction on the Facility or has taken meaningful steps to obtain control of the Project Site in order to commence construction of the Facility." The proposed NOC Form also adds language to section 4(iv)(formerly iii), replacing a simple requirement that the Seller verify that it has "secured control of the Project Site" with language that requires Seller to show that it "has secured – or has submitted all applications and filing fees necessary to secure – all local permitting and zoning approvals for the Project Site necessary to operate and maintain the Facility for at least the length of the Delivery Term." (Hrg. Exh. 4 (JEF-1).)

In response, Mr. Levitas opposed both of these changes, stating that while site control is a valid prerequisite to formation of an LEO, "readiness to begin construction of a project is not a reasonable or permissible requirement for formation of a LEO." (Levitas Direct at p. 16, lines 11-13.) Mr. Levitas continued by stating that because the PPA ultimately "governs the QF's obligations with respect to constructing a facility and placing it in service," readiness for construction "is not germane to formation of an LEO" and the suggested new paragraph 4(iii) should be rejected. (*Id.* at p. 16, lines 15-17.)

Under cross-examination, Mr. Folsom stated that he had no experience "on the construction side" and was not aware of the requirements any locality may impose before a QF could apply for a construction or zoning permit. (Tr. Vol. 3, p. 217, line 25 – p. 218, line 8.) He further admitted that he was not aware of any instance where a proposed QF facility in DESC territory in which a seller had obtained control of a site, signed an NOC, and failed to commence construction. (*Id.* at p. 216, lines 3-7.) Mr. Folsom stated in rebuttal that FERC had authorized such requirements in Order 872. (Folsom Rebuttal, p. 8; line 19 – p. 9, line 1.) In response to Mr. Levitas's testimony and critique, Mr. Folsom stated that DESC had proposed a new amended section 4(iii), reading: "Seller has taken meaningful steps to obtain site control of the Project Site adequate to commence construction of the Facility" and proposed a revised new section 4(iv), to read: "The documents attached hereto as Exhibit B establish that Seller has secured – or has submitted all applications and filing fees necessary to secure – all local permitting and zoning approvals for the Project Site necessary to commence construction of the Facility." (*Id.* at p. 9, line15 – p. 10, line 6.)

In surrebuttal, Mr. Levitas again noted that construction was irrelevant to the issue of formation of a LEO under PURPA, and that preventing formation of an LEO until the "very end of the development cycle" denies QF developers price certainty and "would make it virtually impossible to incur the substantial development costs required to bring a QF to the point of commencing construction." (Levitas Surrebuttal at p. 10, lines 5-11.) Levitas further testified that the revised language testified to by Folsom did not solve the issues:

> While we appreciate the willingness of DESC to consider alternate language, this proposed revision does nothing to address the problem identified in my testimony: a developer is unlikely to be able to apply for construction-related permits, which requires engineered site layout plans, until shortly before construction commences. Application for such permits is thus not a reasonable test of a QF developer's commitment to selling its output to the utility, which is the operative consideration for LEO formation.

(*Id.* at p. 11, lines 3-8.)

Third Party Expert LEI supported maintaining the NOC Form in the form approved in the 2019 Avoided Cost proceeding, with no changes: "we believe that the original language pertaining to site control should be maintained, that no changes be made." (Tr. Vol. 7 (Goulding) at p. 55, line 15.) LEI Report stated that it "believes this requirement is best addressed in the Standard Offer / Form PPA, where it is included already, and as such does not need to be included as a condition to execute the NOC form." (LEI Report at 69.)

c. Termination

The Parties agreed to revise proposed Paragraph 8(ii) of the Proposed NOC Form to read:

> If Seller does not execute a PPA for the Facility within the later of (i) 90 business days after the Submittal Date, or (ii) 60 business days after receipt of an executable PPA from the Company, provided, however, that if a final interconnection agreement for the Facility has not been tendered to Seller five business days prior to the expiration of such deadline, the deadline for execution of the PPA shall be the date that is five business days after the date that the final interconnection agreement is tendered to the Seller.

(Folsom Rebuttal at p. 11; 3-9, (Revised Exhibit JEF-1).)

Intervenors did not raise objections to other NOC termination provisions proposed by DESC.

Commission Conclusions

The Commission determines that the proposed changes to the NOC Form to incorporate storage are commercially reasonable and should be adopted.

The Commission further determines that the proposed changes to the Site Control requirements under Sections 4(iii) and 4(iv) of the proposed NOC Form are unnecessary to the creation of a LEO and are therefore not commercially reasonable. The Commission agrees with LEI that the existing language, in combination with the requirements of the Standard Offer / Form PPA, are sufficient to ensure that QF projects proceed through construction. The changes to the NOC Form are denied in this respect.

The Commission appreciates the work of the Parties and their witnesses in resolving the Intervenors' concerns with the Termination provisions of the proposed NOC Form, and approves them as revised in Revised Exhibit JEF-1.

2. Changes to Form PPA and Standard Offer

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 19

Summary of Evidence

In addition to the proposed changes to the NOC Form, DESC proposes changes to the Form PPA and Standard Offer. Witness Folsom described the rationale for these two documents by noting that the Standard Offer, pursuant to Section 58-41-10 of Act 62, applies to QFs up to 2 MW-AC. The Form PPA applies to other projects. (Folsom Direct at p. 17, line 1 – p. 18, line 13.) Folsom noted that "the revisions proposed in this docket are substantially the same for both documents." (*Id.* at p. 18, lines 12-13.) Folsom describes the changes as "minor" and "primarily consist[ing] of clean-ups that were discovered by DESC in the ordinary course of business." (*Id.* at p. 19, line 14.)

a. Cash collateral

DESC originally proposed to eliminate the option of cash collateral as Performance Assurance under both the Form PPA and Standard Offer. (Folsom Direct at p. 20, lines 16-18.) After objection from CCEBA witness Levitas, cash collateral was returned to the revised document filed with witness Folsom's rebuttal.

b. Increased Insurance Requirements

DESC seeks two types of substantive changes to the insurance requirements in its revised Form PPA and Standard Offer. The first change adjusts the date by which a Seller must deliver a certificate of insurance to the Buyer. The current Form PPA requires delivery "at least fifteen [15] calendar days prior to the start of any work at the Facility." DESC proposes changing that date to "within twenty [20] calendar days of Buyer's request." (Folsom Direct at p. 67 (Hearing Exh. 4 [JLF-2, Attachment D].) While CCEBA originally objected to this change, the objection was withdrawn. (Tr. Vol. 6 at p. 206, lines 20-25).

DESC also seeks permission to increase the amount of insurance required of Sellers under the Form PPA and Standard Offer. Attachment D to the proposed Form PPA changes the amounts of insurance as follows:

> <u>Policy Minimum Limits</u> – from \$2,000,000 to \$4,000,000 aggregate, combined single limit, for bodily injury (including death) or property damage.
>
> <u>Workers' Compensation</u> – from \$1,000,000 to \$2,000,000 each accident for bodily injury by accident or \$2,000,000 each employee for bodily injury by disease.
>
> <u>Environmental Impairment</u> – from \$1,000,000 to \$2,000,000 per occurrence.
>
> <u>Comprehensive Automobile Liability</u> – must provide with bodily injury and property damage with a total limit of at least \$2,000,000 per occurrence which will cover liability arising out of any auto. Previously not required.

Mr. Folsom testified that these provisions were "revised to conform with Dominion Energy, Inc.'s insurance requirements." (Folsom Direct at p. 23, lines 3-5.) On cross-examination, he conceded that DESC was requesting these changes "even though Dominion has not had any insurance claims exceeding coverages at any QFs in its territory since the … adoption of the last PPA." (Tr. Vol. 3, p. 206, lines 1-10.) He also stated that "we forwarded our coverages to the risk management folks in Richmond – at Dominion Energy home office. And they did their research, looked at what the standard corporate requirements are, and these are the recommendations that they came back to us for use in these PPAs." (*Id.* at p. 207, lines 12-17.) CCEBA witness Levitas objected to these increases in his Direct testimony and stated that "arbitrary increases in the amount of insurance that a QF developer must carry increase the cost of QF projects and needlessly discriminates against independent power producers." (Levitas Direct at p.10, line 22 – p. 11, line 1.)

In rebuttal, Mr. Folsom, for the first time, offered a rationale for the insurance increases, noting "these increases reflect, in part, the deployment of emerging technologies, which are quickly becoming a more viable option for these generators. For example, these complex facilities may implement battery storage or utilize inverter-based generation while remaining within the bounds of PURPA, but are nevertheless well in excess of 80MW-DC." (Folsom Rebuttal at p. 5, lines 5-7.) According to Mr. Folsom, these technologies may "introduce additional safety concerns." (*Id.* at p. 5, line 9.) On surrebuttal, Mr. Levitas noted that this newfound explanation failed to tie the proposed coverage amounts to any particular risk, or "cite a single instance in which QF coverage has been needed to protect DESC and its ratepayers from loss, let alone one where the current coverage levels have proved to be inadequate." (Levitas Surrebuttal at p. 7, lines12-14.) Moreover, Mr. Levitas stated, QF developers already have significant financial incentive to return to operation as soon as possible and the risk to third parties is low. (*Id.*) Finally, Mr. Levitas testified that "[w]hile it is true that the addition of storage components to QF facilities increases their economic value, that alone is not a basis for doubling coverage amounts for personal injury, workers' compensation, and automobile liability insurance." (*Id.* at p. 8, lines 7-10.) CCEBA's position is that the required coverage levels should be maintained with new automobile insurance minimum coverage limited to $1,000,000.

In the LEI Report, LEI reviewed the testimony and coverages required by other utilities. The LEI Report noted that LEI "is not convinced that the proposed changes are necessary to protect customers" but recognized that the "coverage levels are generally obtainable in the marketplace." (LEI Report at 64.) LEI ultimately recommended that current coverages be maintained for the Standard Offer for smaller QFs, while DESC's suggested changes take effect only for the Form PPA. (*Id.* at 65.) On cross-examination, LEI witness Goulding acknowledged that the requested insurance amounts were not scaled to the size of the facility, not determined by risk, and not determined by what technology was present at the facility. (Tr. Vol. 7, p. 95, lines 3-16; 98, lines 5-11.)

Commission Conclusions

Given CCEBA's withdrawal of its objection to the change in the dates by which a Seller must provide a certificate of insurance, the Commission approves the proposed change to require delivery of the certificate within 20 days of demand by Buyer.

The Commission finds that DESC has not shown that the proposed increases in minimum insurance coverage amounts are justified by any particular risk or condition of operation at a QF facility, whether subject to the Form PPA or the Standard Offer. There is no demonstrated connection between the requested increases and any particular risk, whether physical or economic. The justification of compliance with parental corporate practice is not sufficient to impose additional burdens on QF developers. The increases are therefore denied, and the language of the Form PPA and Standard Offer will remain as approved by the Commission in the 2019 procedure, with the exception that the addition of automobile liability coverage is authorized at a minimum of $1,000,000 per occurrence.

c. Surety Bond

<u>Summary of the Evidence</u>

DESC also seeks to amend the form of the Surety Bond required in Exhibit F to the Form PPA and Standard Offer. Mr. Folsom described the justification for the change by noting "As the integration of DESC into Dominion Energy, Inc. continues, the Form of Surety Bond has been revised to conform with Dominion Energy's form for such a bond." (Folsom Direct at p. 23, lines 7-9.) The proposed revised paragraph 8 of the the proposed Surety Bond Form has two changes to which CCEBA has objected. First, the proposal would change the time for payment upon demand by the Surety to an Obligee from 15 days to 10. (Folsom Direct at pp. 188, 337 (Exhibits JEF 2 and 3, Attachment F, para. 7.) Further, the same paragraph adds a provision which states:

> … Surety shall pay Obligee the amount demanded in freely transferable funds, *without defense, reduction, or offset,* up to and including the Bond Amount, in accordance with payment instructions set forth in the demand. There shall be no further condition to Surety's obligation to pay Obligee, and *Surety expressly waives any right to setoff, cross-claim, or any other claim* that Surety or Principal may now have or at any time hereafter may acquire.

(*Id.*) (emphases added).

Witness Levitas noted that both these changes are different from the bond form previously approved by the Commission in the 2019 proceeding and DESC has provided "no rationale." (Levitas Direct at p. 11, line 8.) Mr. Levitas stated that, in his experience "providers consider a 10-day payment period to be too short and are often unwilling to execute surety bonds containing such a short payment period." (*Id.* at lines 21-22.) Levitas further objected to the waiver of defenses language noting that "even though the surety may have a legal right under the applicable governing law to assert as defense – such as that the QF did not actually breach the PPA – DESC would force the surety to forego all such legal defenses." (*Id.* at p. 12, lines 7-9.) Mr. Levitas characterized that provision as a "poison pill that will very likely dissuade any surety from issuing a bond in favor of a QF." (*Id.*)

On rebuttal, Folsom raised no further defense of the provisions, noting only that "DESC disagrees with Witness Levitas's characterization of the second change as a 'poison pill' given that DESC's parent company has utilized this form surety bond in the marketplace for a number of years." (Folsom Rebuttal at p. 4, line 21 – 5, line 3.) When asked on cross-examination if he were aware of any losses against which DESC had sought payment under the original surety bond and the surety had refused to pay, Folsom responded "None that I'm aware of." (Tr. Vol. 3, p. 211, lines 21-25.) In October, when subject to additional cross-examination, Folsom confirmed that the company did not "have any specific catastrophic type scenarios to point to." (Tr. Vol. 8, p. 136, line 20-21.)

Though he had no "specific example" of a project successfully obtaining a surety through the use of the revised bond form, Mr. Folsom stated that he "had been informed that this form is routinely used to secure a surety bond." (Tr. Vol. 3, p. 212, lines 9-19.) On Surrebuttal, Mr. Levitas stated that Folsom's testimony failed to provide any justification for the changes or any examples of developers in other states being able to obtain surety bonds using the changed form. (Levitas Surrebuttal at p. 6, lines 1-5.)

LEI also reviewed the surety bond issue and concluded, "it is LEI's view that modifying forms to conform with parent company practice is not sufficient justification for making a change. Changes should instead respond to a material risk to customers before being proposed." (LEI Report at 66.) While LEI recommended that any future changes proposed by DESC "be justified first and foremost in response to a material impact to customers" it nevertheless recommended adoption of the Form of Surety Bond proposed by DESC because "we do not believe that QF developers would be significantly harmed in this instance." (*Id.*)

Commission Conclusions

The Commission, having reviewed all of the testimony, exhibits, and arguments submitted on this issue by all Parties, concludes that it agrees with LEI that material changes to approved Form PPAs and Standard Offers and their attachments should respond to a material risk to customers "before being proposed." The Commission does not, however, agree with LEI that the changes to the Surety Bond form are harmless and therefore immaterial. The Commission finds compelling the testimony of Witness Levitas as to the effect of these types of changes on QF developers. While adverse affect on QF developers is not in and of itself determinative of the issue, where, as here, DESC has failed to provide any evidence of any particular risk to customers that is being addressed by the change, the change cannot be approved.

d. Ancillary Services

The Parties disagree over the definition of "Energy" included in the Proposed Form PPA and Standard Offer. The definition includes the following language:

> "Energy" shall also include all electrical products produced by or related to the Facility, including spinning reserves, operating reserves, balancing energy, regulation service, ramping capability, reactive power and voltage control, frequency control and other ancillary or essential reliability service products, or any benefit Buyer otherwise would have realized from or related to the Facility if Buyer rather than Seller had constructed, owned or operated the Facility, it being the Parties' intent that all such benefits and entitlements in addition to electrical output that flow to the owner or operator of the Facility, whether existing as of the Effective Date or at any time furing the Term, belong to Buyer at no additional cost to Buyer.

(Exhibit 7 to Second Amended Application, p. 7.)

Witness Levitas testified that Section 58-41-20 of the Energy Freedom Act requires that "each electric utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electric utility, including, but not limited to, energy, capacity, and ancillary services provided by or consumed by small power producers…" (Levitas Direct at p. 13, lines 1-4.) Because the Form PPA as currently worded would provide that "ancillary or other essential reliability service products . . . *belong to the Buyer at no additional cost to Buyer*," Levitas argued that DESC's "avoided cost rates should include the cost of procuring ancillary services that are avoided by virtue of its purchase of 'energy' from QFs under PURPA." (*Id.* at p. 13, lines 19-21.) Because Levitas believes the rate proposed by DESC does not do that, he suggested that "the conveyance of and compensation for reactive power is properly dealt with in the interconnection agreement between the parties and not in the PPA," (*Id.* at p. 14, lines 1-2) because the DESC standard Interconnection Agreement ("IA") "explicitly requires that it pay the Interconnection Customer for reactive power that the Interconnection Customer provides or absorbs outside of a prescribed range required by the IA."

DESC witness Kassis, in his rebuttal testimony, confirmed that "Ancillary Services are not included in the calculation of avoided costs." (Kassis Rebuttal at p. 11, line 19.) He noted that the Interconnection Agreement is generally negotiated by the Transmission Provider while the PPA is negotiated by the generation purchaser which can be, but is not always, the same entity. (*Id.* at p. 12, line 21 – p. 13, line 2.) He thus recommended maintaining the structure as proposed by DESC. In the case of reactive power, which he described as an ancillary service, "any decision about a solar QF's ability to even provide ancillary services would be fact specific. Only once this is determined, would the value of such services be determined on a case-by-case basis, taking into account the specific capabilities of the generating plant." (*Id* at p. 13, lines 5-9.) Kassis argued that "there is no need to adopt Witness Levitas's suggestion at this time and, as in the example noted above where DESC is not the party to both the IA and the PPA, it may have unintended negative consequences." (*Id.* at 13, lines 15-17.)

On surrebuttal, Levitas stated that Kassis's testimony was internally inconsistent and "confirmed the need for clarification." (Levitas Surrebuttal at p. 12, line 3.) He testified that while Kassis confirmed that ancillary services such as reactive power were not included in the calculation of avoided costs, the definition of Energy gives such services to DESC "at no additional cost." (*Id.* at 12, lines 8-12.) He argued that, while Kassis may contend that such terms can be separately negotiated based on fact-specific circumstances, the net result is confusing and "runs afoul of Act 62, which requires that the Commission treat small power producers on a 'fair and equal footing with electrical utility-owned resources' by ensuring that avoided cost rates 'fully' reflect the utility's avoided costs with a methodology that 'fairly accounts' for costs avoided, '*including … ancillary services*.'" (*Id.* at p. 12, lines 13-17.) He suggested "at a minimum, the Commission should require DESC to remove the language in the PPA purporting to give DESC ancillary services for free.") (*Id.* at p. 12, lines 19-20.)

<u>Commission Conclusions</u>

The Commission concludes that witness Levitas has identified a real issue with the language of the definitions in the Form PPA and Standard Offer. If ancillary services are not included in DESC's calculation of avoided costs, then the language providing that such services are to be provided "at no additional cost to Buyer" could be, at the least, confusing. While the Commission understands and appreciates that compensation for such services could be independently negotiated depending on the fact-specific circumstances of a given QF facility, the presence of that language in the Form PPA definitions could lead to improper results which violate the dictates of Act 62. Therefore, the Commission finds that DESC has not justified the inclusion of ancillary services as energy products provided by QFs to DESC free of charge and will require such language be removed from the definition of Energy in the Form PPA and anywhere else it appears in DESC's proposed forms and documents.

VII. Ordering Paragraphs

NOW THEREFORE, IT IS HEREBY ORDERED THAT:

1. The Commission adopts a fixed VIC of $0.47/MWh for Tranche 1 and a fixed VIC of $0.73/MWh for any PPA executed prior to a future updated integration charge adopted by this Commission pursuant to the completion of an independent integration study.
2. The Commission will initiate an independent integration study consistent with Order No. 2020-244 and the recommendations of ORS and LEI that should be completed prior to DESC's next avoided cost proceeding.
3. In future avoided cost filings, a utility's filings must ensure that underlying assumptions, data, and results can be independently reviewed by the parties and the Commission, as required by statute.
4. The Commission adopts, with Witness Burgess's modifications, the Dominion Energy North Carolina VIC mitigation protocol, as well as the LEI recommendations to eliminate DESC's proposed two-strike rule, as it is unfair to QFs and potentially harmful to customers.
5. The Commission rejects DESC's proposed changes to the Site Control provisions of paragraphs 4(iii) and 4(iv) as unnecessary to the creation of a Legally Enforceable

Obligation under PURPA and therefore not commercially reasonable, and orders those proposed provisions stricken from the proposed NOC Form

6. The Commission finds that the Parties have agreed upon commercially reasonable language for Paragraph 8(ii) of the Proposed NOC Form related to termination as submitted in Revised Exhibit JEF-1 and orders that language be adopted.
7. The Commission rejects DESC's proposed amendments to the Form PPA and Standard Offer related to proposed increases in minimum insurance coverage amounts as not justified by any particular risk or condition of operation at a QF facility, and orders DESC to retain the insurance requirements previously approved by the Commission in 2019.
8. Nevertheless, the Commission finds the addition of required automobile liability insurance with bodily injury and property damage with a total limit of at least $1,000,000 per occurrence to be reasonable and orders DESC to adopt such a requirement.
9. The Commission rejects DESCs proposed changes in revised paragraph 8 of the Surety Bond form (Exhibit F to the Form PPA and the Standard Offer) as unjustified by relation to any particular risk or condition of operation at a QF Facility and therefore commercially unreasonable. The Commission orders DESC to retain the Surety Bond form approved by this Commission in the 2019 Avoided Cost proceeding.
10. The Commission finds that DESC has not justified the inclusion of ancillary services as energy products provided by QFs to DESC free of charge, and requires such terms be removed from the definition of "Energy" in the Form PPA and Standard Offer. The Commission recommends that the cost of ancillary services be addressed in

Interconnection Agreements entered into with individual interconnection customers on a case-by-case basis.

BY ORDER OF THE COMMISSION:

Justin T. Williams, Chairman
Public Service Commission of
South Carolina

Respectfully submitted, this 3rd day of November, 2021.

Respectfully Submitted,

/**s**/Richard L. Whitt
Whitt Law Firm, LLC

/**s**/John D. Burns
Carolinas Clean Energy Business Association
General Counsel
Admitted *Pro Hac Vice*

Both as Counsel for Intervenor, Carolinas Clean Energy Business Association.

November 3, 2021